4. Choice of Technology and Cost Function

The typical size of wind generators commercially used has grown from 12.5-m rotor diameter in the early 1980s to 40-m diameter in the mid 1990s. A modern 40-m rotor diameter wind turbine typically corresponds to 0.5 MW of capacity. It is likely that during the next thirty years, due to improvements in design, 0.75- to 1-MW generators will be used more. However, the very large (1.5 to 3 MW) generators which were developed by funding from U.S., German, and British wind programs have not yet achieved commercial viability.

Experience of the last two decades shows that increasing size does not necessarily decrease generator costs per kW capacity, although the larger size does provide a scale economy related to operating and maintenance costs. The cost of servicing a wind generator is the same for all generators which are less than 50 m in diameter. For larger turbines, large cranes are needed for most repairs which increases maintenance costs and, possibly, some first costs such as construction of wider access roads.

In this study, we used a prototypical 0.5-MW (40-m rotor diameter, 50-m hub height) turbine in evaluating the sites. This follows from the argument that such a size is big enough to sweep a large area and yet small enough to keep the maintenance costs low. It also appears that the industry has been evolving in that general direction.

Contributors to the initial cost of a wind plant are the cost of the generators, the cost of the land where the generator is erected (this is generally quite small), costs associated with connecting the individual generators to the grid, and costs of building access roads. Operating costs include: maintenance costs, rents for the areas covered by the wind farm, and labor costs. In this study, using digital elevation maps to determine wind sites, resulted in an improved methodology for quantifying the distance to existing transmission lines and roads. Detailed estimation of the unit costs for the items listed above was not one of the main objectives of this study. However, information available in existing studies was incorporated in the cost calculations. Clearly, cost estimates could be improved by refining the unit cost based on recent surveys of equipment costs, land values, land rental rates, road construction costs, etc. Other factors such as proximity to other wind farms and population centers could also be included in the estimation.

Wind Power Plant Capital Outlay[6]

Wind Turbine Generators[7]

The trends in published transaction costs (cost plus profit) for wind power projects show that the price paid for wind power plants in California and Denmark fell dramatically in the 1980s (Gipe 1995). In California, the price in 1992 dollars came down from 4 000 $/kW in 1981 to 1 200 $/kW in 1987. NREL (1996) estimates the 1994 costs in the range 800 to 1 000 $/kW. The cost used by Union of Concerned Scientists based on prices they obtained from US Windpower is 1 032 $/kW for a 50-MW wind farm in the Midwest in 1992 dollars (Brower et al. 1993). In this study we used a cost of 1 000 $/kW. This cost is reduced by about one percent every year into the future. This figure includes the equipment, construction costs, land, and permits.

Connecting to the Grid [8]

It is assumed that the wind farms would be connected to the grid through a substation. The line between the substation and the grid would be a high voltage line, typically 115 kV. Transmission lines from the substation to the grid will require 100 000 to 130 000 $/km depending on the terrain and a fixed hookup charge of $300 000. Within the site, turbines are assumed to be connected to the substation by low voltage lines of 4.16 kV at a cost of 50 000 $/kW. For each site, a $3 000 000 substation charge is assumed.

Access Roads[9]

All weather access is required by maintenance crews. These roads also need to be built such that heavy equipment can be moved to the sites during construction. For this study 4-m (about 12 ft) wide roads are assumed necessary. The construction of roads are assumed to cost 22 000 $/km. For the land covered by the roads, a one-time cost of 375 000 $/km^2 ($1 500 per acre) is assumed.

6 All costs and revenues are in 1995 dollars.

7 cost of generators = generation capacity (kW) × 1 000 $/kW

8 cost of connecting to the grid = $300 000 hookup charge + 130 000 $/km × distance to transmission lines (km) + 50 000 $/km × lines within farm (km) + $3 000 000 substation cost

9 cost of connecting to the roads = [22 000 $/km × distance to roads (km)] + [land value ($/km^2) × 0.006 km^2/km land requirement × distance to roads (km)]

Operating Costs

Maintenance Costs[10]

Maintenance costs compiled by Gipe (1995) indicate that they are about 0.012 \$/kWh in 1992 currency. For some sites this may be substantially lower or higher. For this study we use 0.012 \$/kWh.

Land Rent[11]

Wind turbines occupy only a small fraction of the land area they are built over. Usually, the area can still be used for farming or grazing animals. In California, much of the sites are either on ridges or areas which are only suitable for grazing. The major exception is the Palm Springs-Whitewater area which is mostly rural residential. In this study, we use a cost of 10 000 $\$/km^2$ (\$40 per acre) per year in all areas except the Palm Springs-Whitewater area. For the Palm Springs area, we use 25 000 $\$/km^2$ (\$100 per acre) per year. It is assumed that each 500-kW windmill will require an area of 0.04 km^2 (10 acres), which is based on the generator-spacing assumptions covered in the next section.

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[10] maintenance cost = 0.012 \$/kWh × capacity (kW) × 0.3 × 8 760 h

[11] rent for the wind farm = rent ($\$/km^2$) × 0.04 km^2/wind generator × 2 generators/1 000 kW × site capacity (kW)

5. Capacity and Profitability of Wind Resources

In this section, costs and estimated revenues for wind generators at each of the selected 36 sites are processed to provide a preliminary characterization of capital costs and profitability of wind resources in California. A simple levelized cost and revenue method is used. The summary section of the spreadsheet which serves as the database for the information on these sites is presented in Appendix A.

Characterization of the Wind

For each of the 36 sites selected, diurnal wind speeds (typically recorded every 3 hours) for four seasons (winter, spring, summer, and autumn), monthly average wind speeds, and annual average wind speeds are developed, based on the data collected in the CEC and DOI studies. Wind data are available for many of the sites at the above level of detail. The exceptions are the sites on the coastal mountains and in San Diego county. For these locations, diurnal average wind patterns are available either only for the whole year or only for winter and summer (as opposed to four seasons). On the other hand, for some of the other sites, there are hourly chronological data for more than one year. Data for the different sites are not necessarily coincident. They are typically for a year during the late 1970s or early 1980s. It is noted that sites with similar annual average wind speeds may have very different seasonal and diurnal patterns. Wind patterns for selected sites are presented in Figures A-1 to A-5 in Appendix A.

Estimation of Power

As mentioned above, for this study, a generic wind turbine of 40-m diameter and 50-m hub height is used. The wind speed at 10 m is used to estimate the wind speed at 50 m,[12] and similar wind profiles for each of the locations are assumed, for lack of detailed information.

The power coefficient of a wind turbine is defined as the power delivered by the generator divided by the total power available in the cross-sectional area of the wind stream spanned by the blades. The maximum value for the power coefficient for the optimal blade design is 0.593. In practice, windmills can achieve power coefficients in the range of 0.4 to 0.45 (Eldridge 1975), and in this study we assumed a power coefficient of 0.45.

Given the above assumptions, the wind patterns for the sites in consideration are converted into potential power patterns.

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12 using the formula $(V_{50}/V_{10})^7 = (50/10)$; where V_{50} = wind velocity at 50 m and V_{10} = wind velocity at 10 m

Estimation of Revenues by Spreadsheet

The results of Elfin simulations are reported below, but a preliminary spreadsheet analysis of wind site profitability was conducted as follows. Elfin models the market and delivers results for both capacity expansion and dispatch. Electricity prices depend on what kinds of wind resources are built, and how they are dispatched. In other words, decisions about wind turbines and electricity prices are endogenous to the model. However, since the wind resources are small compared to other generating assets, we may assume that decisions about wind generation will not affect electricity prices significantly. With this assumption, electricity prices generated by Elfin in a previous run with the generic wind resource were used. Prices are generated with a diurnal pattern for each season. Superimposing these prices with the wind data, revenues at each of the 36 locations are calculated.

Estimation of Resource Capacity

Windmills are placed (positioned) in varying styles at wind farms. How closely the mills are placed relative to each other affects the performance of the site. The optimal site design depends on many factors such as the profile of the wind, the terrain, etc. Creating designs for each site is beyond the scope of this study so the following was assumed: (1) for the ridge sites, the windmills were placed three diameters apart, and (2) for the flatter areas, windmills were again placed three diameters apart across the wind and eight diameters apart along the prevalent wind. Based on these assumptions and the sizes of the 36 sites given in the CEC and DOI studies, the potential capacity for each site was estimated. If the size of the resource is not given in the CEC or DOI reports, they are estimated using GIS.

Capital-Cost and Profitability Curves

The wind capital cost curves presented in this report (Figures 16 and 17) show the amount of annual generation at different levels of initial capital outlay in the years 2010 and 2030. The resources in these curves are ordered from the highest annual generation to the lowest, for a given amount of initial capital outlay (Tables 3 and 4). The curves show that the desirability of the resources in California at different sites vary considerably and exhibits a smooth diminishing-return to capital. It appears that, in the year 2010, for a $\$8.2 \times 10^9$ capital investment, there is a potential generation of about 43 TWh/a. The same cost goes down to $\$6.5 \times 10^9$ in the year 2030. In this study, it is assumed that the capital costs for wind development will decline at a rate of 1.15%/a during the study period.

Figure 16. Capital Costs for California Wind Generation in 2010

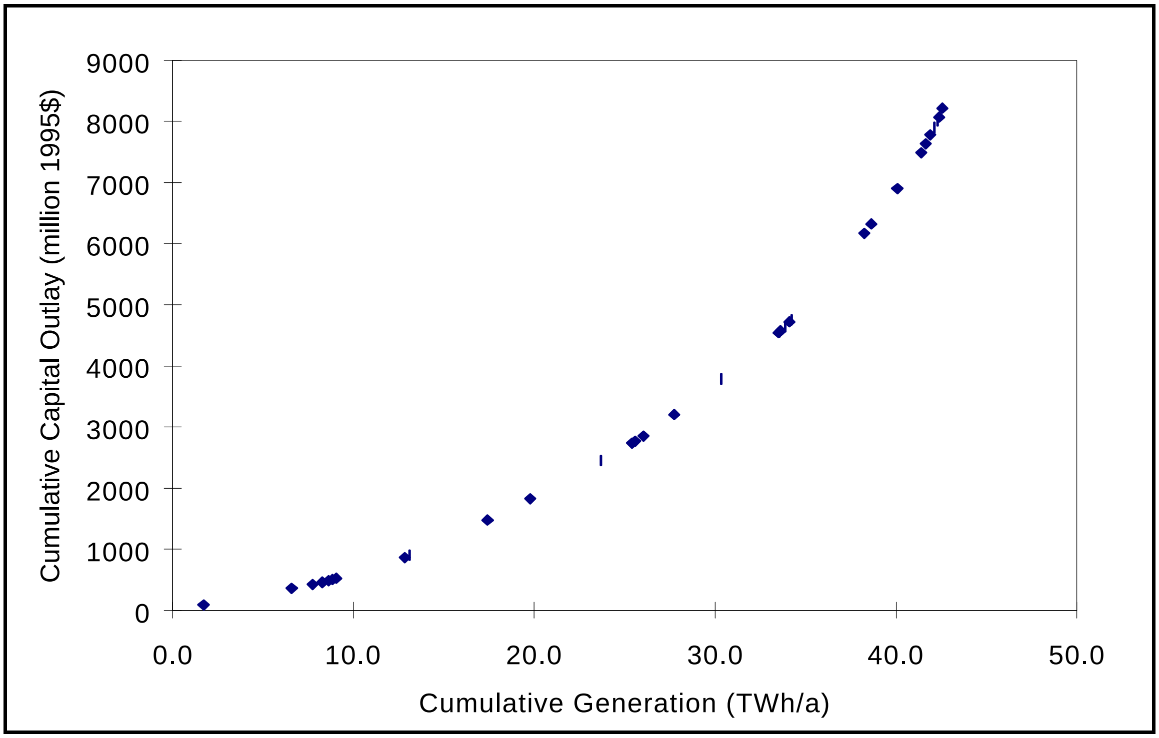


Figure 17. Capital Costs for California Wind Generation in 2030

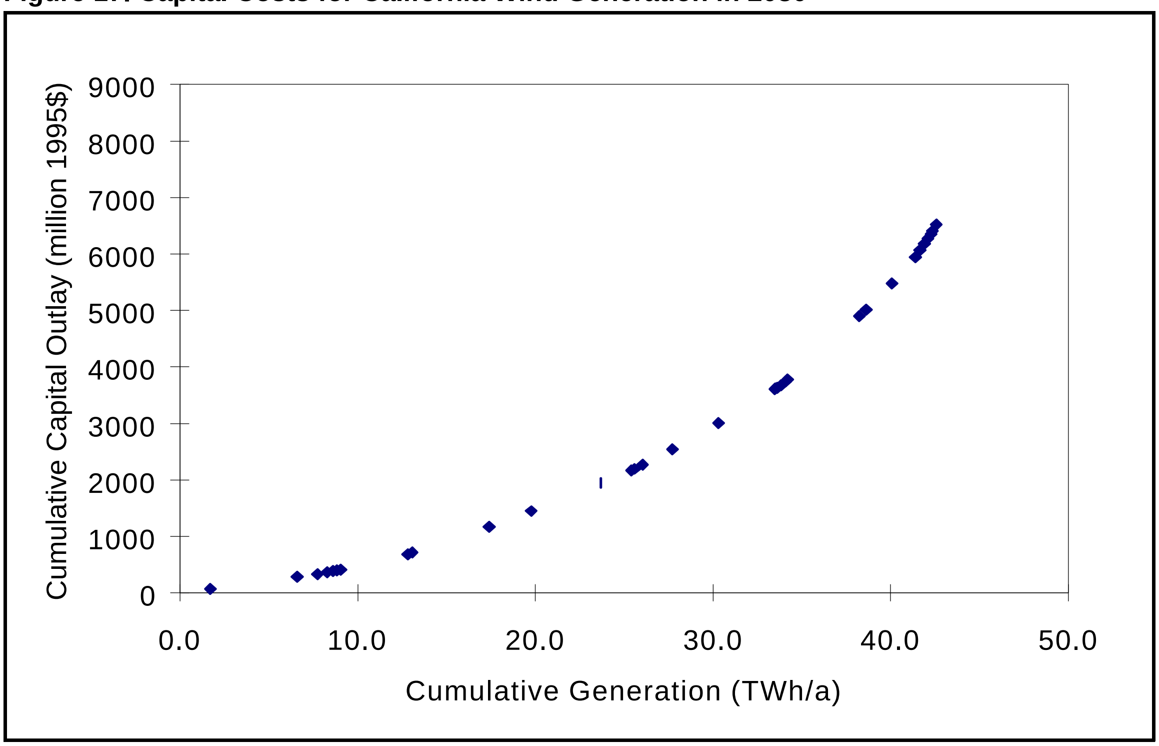


Table 3. Capital Costs Wind Generation in 2010

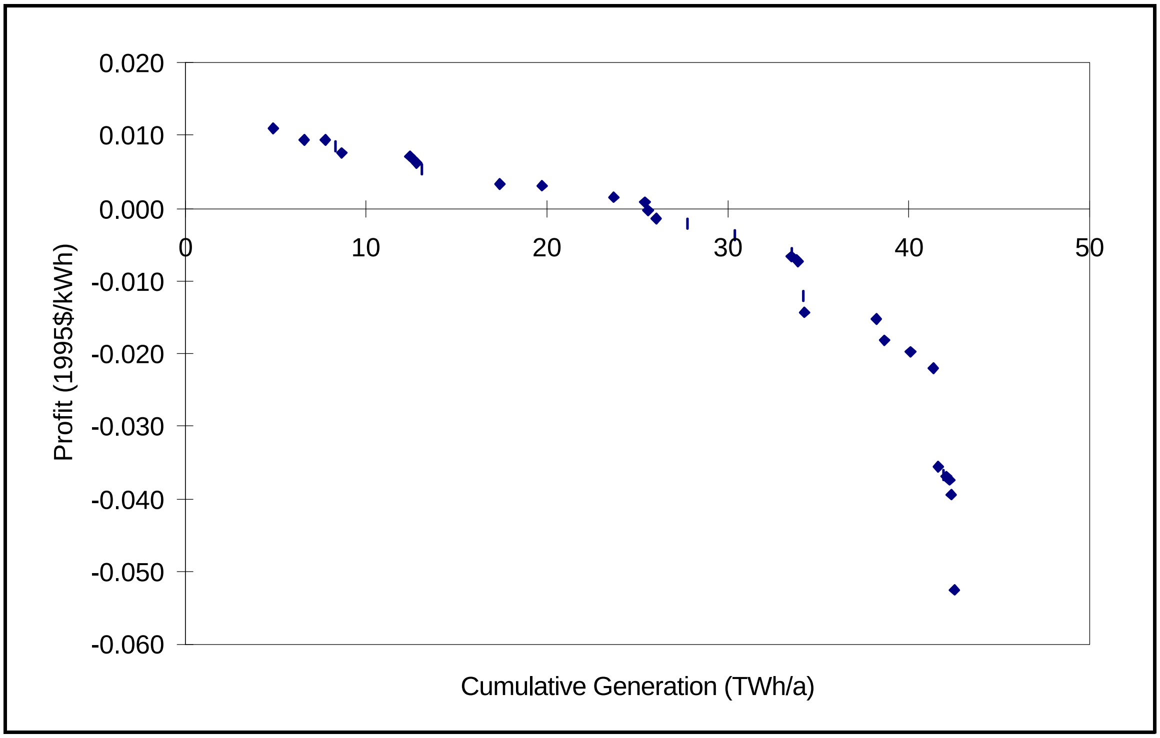
Resource	Cumulative Generation (TWh/a)	Cumulative Capital Outlay (million $)
26	1.7	92
6	6.6	361
27	7.7	424
30	8.3	459
31	8.6	485
29	8.8	503
28	9.1	522
2	12.8	866
24	13.1	897
4	17.4	1476
1	19.8	1826
7	23.7	2449
3	25.4	2735
16	25.6	2767
9	26.0	2853
34	27.7	3204
21	30.3	3786
5	33.5	4542
15	33.5	4551
10	33.6	4575
25	33.8	4635
12	34.1	4719
32	34.2	4751
8	38.2	6171
17	38.6	6318
11	40.1	6903
23	41.4	7486
35	41.7	7634
19	41.9	7782
20	42.1	7900
18	42.3	8006
33	42.4	8067
36	42.6	8216

Table 4. Capital Costs of California Wind Generation in 2030

Resource	Cumulative Generation (TWh/a)	Cumulative Capital Outlay (million $)
26	1.7	73
6	6.6	286
27	7.7	336
30	8.3	365
31	8.6	385
29	8.8	399
28	9.1	414
2	12.8	688
24	13.1	713
4	17.4	1172
1	19.8	1450
7	23.7	1945
3	25.4	2172
16	25.6	2198
9	26.0	2265
34	27.7	2544
21	30.3	3007
5	33.5	3607
15	33.5	3614
10	33.6	3633
25	33.8	3681
12	34.1	3747
32	34.2	3773
8	38.2	4900
17	38.6	5018
11	40.1	5482
23	41.4	5944
35	41.7	6062
19	41.9	6180
20	42.1	6273
18	42.3	6358
33	42.4	6406
36	42.6	6524

We are assuming that, under the future regime, electricity prices will be tightly coupled to marginal costs. Under such circumstances, calculations given above can be taken one step further to include revenues and to calculate profitability of sites. Marginal electricity costs obtained from previous Elfin runs for California are used to evaluate the revenues for each of the sites yielding profitability estimates. Sites are ordered in terms of profitability and a profitability curves are presented in Figures 18 and 19 with information on the ordering of the sites in Tables 5 and 6, respectively.[13] Figure 18 indicates that in the year 2010, up to about 26 TWh/a can be generated with positive profitability, that is, above simple break-even on costs. Figure 18 also shows the interesting suggestion that, output could be increased to about 34 TWh/a with only a marginal loss of 0.01 $/kWh, and to about 40 TWh/a with a marginal loss of 0.02 $/kWh. Figure 19 indicates that, in the year 2030, up to about 34 TWh/a can be generated with positive profitability, and output could be increased to about 41 TWh/a with only a marginal loss of 0.005 $/kWh. These results do not change much if average prices rather than time-varying pool prices are used for the above analysis. This is due to the fact that pool prices are relatively constant throughout the year except for summer afternoons. The average pool prices used in this paper are shown in Figure 20.

Figure 18. Profitability of Wind Resources in 2010



[13] Note that “profitability” here means the difference between revenues and costs, with no regard for required returns on investment.

Figure 19. Profitability of Wind Resources in 2030

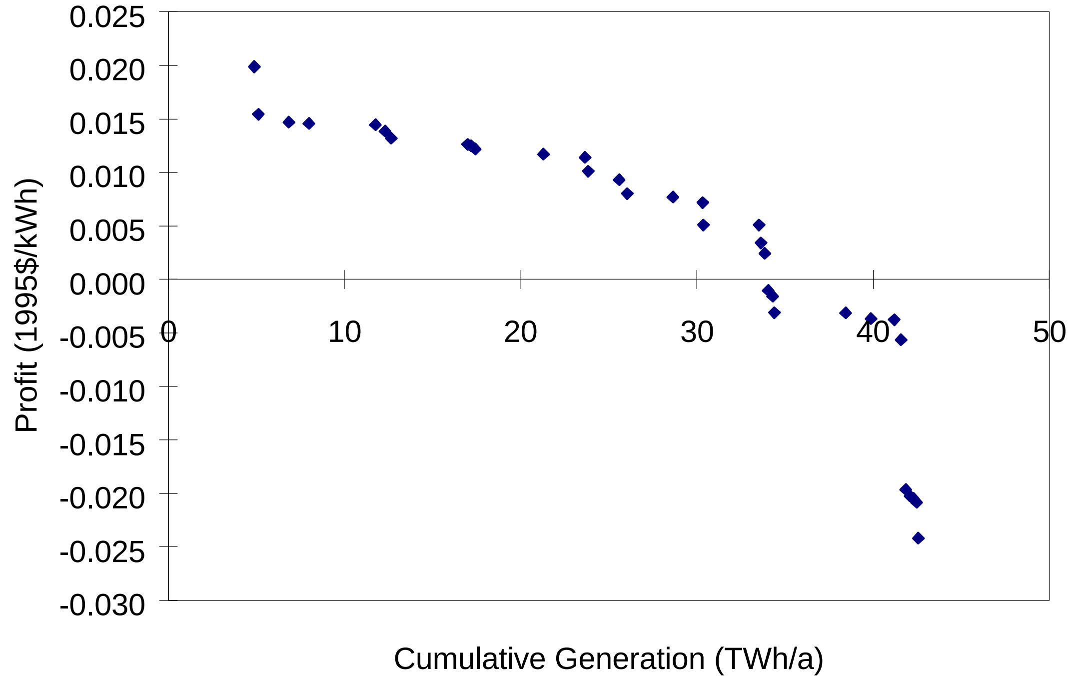


Table 5. Profitability of Wind Resources in 2010

Resource	Cumulative Generation (TWh/a)	Profit/kWh ($)
6	4.881	0.011
26	6.595	0.009
27	7.737	0.009
30	8.283	0.008
31	8.626	0.008
2	12.407	0.007
29	12.621	0.007
28	12.836	0.006
24	13.075	0.005
4	17.410	0.003
1	19.770	0.003
7	23.654	0.002
3	25.410	0.001
16	25.586	0.000
9	26.038	-0.002
34	27.727	-0.002
21	30.322	-0.004
5	33.489	-0.006
15	33.523	-0.007
25	33.745	-0.007
10	33.842	-0.007
12	34.104	-0.012
32	34.198	-0.014
8	38.241	-0.015
17	38.625	-0.018
11	40.078	-0.020
23	41.391	-0.022
35	41.650	-0.036
19	41.898	-0.037
20	42.094	-0.037
18	42.270	-0.037
33	42.369	-0.040
36	42.563	-0.053

Table 6. Profitability of Wind Resources in 2030

Resource	Cumulative Generation (Twh/a)	Profit/kWh ($)
6	4.881	0.020
24	5.120	0.015
26	6.834	0.015
27	7.976	0.015
2	11.758	0.014
30	12.303	0.014
31	12.646	0.013
4	16.982	0.013
29	17.196	0.013
28	17.410	0.012
7	21.294	0.012
1	23.654	0.011
16	23.830	0.010
3	25.586	0.009
9	26.038	0.008
21	28.633	0.008
34	30.322	0.007
15	30.357	0.005
5	33.523	0.005
10	33.620	0.003
25	33.842	0.002
36	34.036	-0.001
12	34.298	-0.002
32	34.392	-0.003
8	38.435	-0.003
11	39.888	-0.004
23	41.201	-0.004
17	41.585	-0.006
35	41.844	-0.020
19	42.092	-0.020
20	42.288	-0.020
18	42.464	-0.021
33	42.563	-0.024

Figure 20. Average Pool Price for California